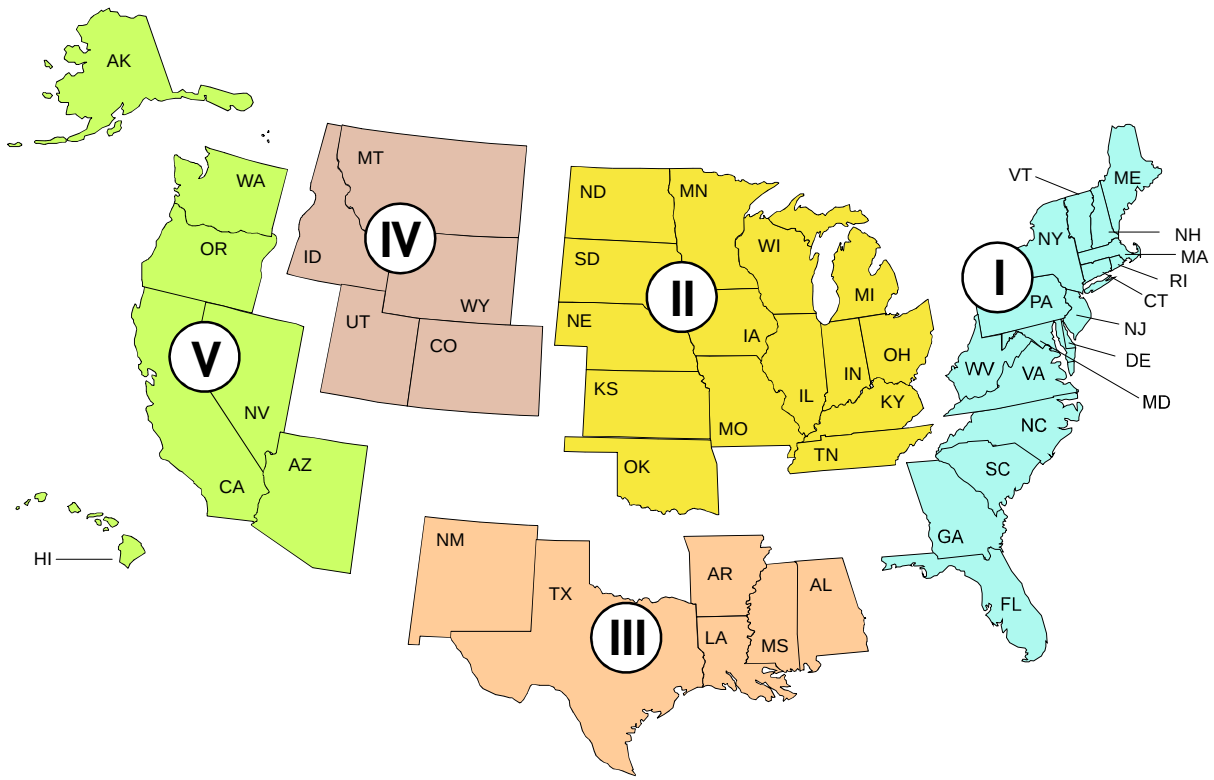
Petroleum Market Module

The NEMS Petroleum Market Module (PMM) projects petroleum product prices and sources of supply for meeting petroleum product demand. The sources of supply include crude oil (both domestic and imported), petroleum product imports, unfinished oil imports, other refinery inputs (including alcohols, ethers, bioesters, corn, biomass, and coal), natural gas plant liquids production, and refinery processing gain. In addition, the PMM projects capacity expansion and fuel consumption at domestic refineries.

The PMM contains a linear programming (LP) representation of U.S. refining activities in the five Petroleum Area Defense Districts (PADDs) (Figure 9), linked to a simplified world refining industry representation used to model U.S. crude and product imports. The U.S. segment of the LP model is created by aggregating individual U.S. refineries within a PADD into two types of representative refineries, and linking all five PADD's and world refining regions via crude and product transit links. This representation provides the marginal costs of production for a number of conventional and new petroleum products. In order to interact with other NEMS modules with different regional representations, certain PMM inputs and outputs are converted from PADD regions to other regional structures and vice versa. The linear programming results are used to determine end-use product prices for each Census Division (shown in Figure 5) using the assumptions and methods described below.

Figure 9. Petroleum Administration for Defense Districts



Source:Energy Information Administration,Office of Integrated Analysis and Forecasting.

Key Assumptions

Product Types and Specifications

The PMM models refinery production of the products shown in Table 11.1.

The costs of producing different formulations of gasoline and diesel fuel that are required by State and Federal regulations are determined within the linear programming representation of refineries by incorporating the specifications and demands for these fuels. The PMM assumes that the specifications for these fuels will remain the same as currently specified, with a few exceptions: the sulfur content, which will be phased down to reflect EPA regulations for all gasoline and diesel fuels; and, benzene content, which will be reduced in gasoline beginning in 2011.

Table 11.1. Petroleum Product Categories

Product Category	
Motor Gasoline	Conventional Unleaded, Oxygenated, Reformulated
Jet Fuel	Kerosene-type
Distillates	Kerosene, Heating Oil, Low-Sulfur-Diesel, Ultra-Low-Sulfur-Diesel
Residual Fuels	Low Sulfur, High Sulfur
Liquefied Petroleum Gases	Propane, Liquefied Petroleum Gases Mixed
Petrochemical Feedstocks	Petrochemical Naptha, Petrochemical Gas Oil, Propylene, Aromatics
Others	Lubricating Products and Waxes, Asphalt/Road Oil, Still Gas Petroleum Coke, Special Naphthas, Aviation Gasoline

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Motor Gasoline Specifications and Market Shares

The PMM models the production and distribution of three different types of gasoline: conventional, oxygenated, and reformulated (Phase 2). The following specifications are included in the PMM to differentiate between conventional and reformulated gasoline blends (Table 11.2): Reid vapor pressure (RVP), benzene content, aromatic content, sulfur content, olefins content, and the percent evaporated at 200 and 300 degrees Fahrenheit (E200 and E300). The sulfur content specification for gasoline has been reduced annually through 2007 to reflect recent regulations requiring the average annual sulfur content of all gasoline used in the United States to be phased-down to 30 parts per million (ppm) between 2004 and 2007.[1] The sulfur specifications assumed for each region and type of gasoline are provided in Table 11.3.

Conventional gasoline must comply with antidumping requirements aimed at preventing the quality of conventional gasoline from eroding as the reformulated gasoline program is implemented. Conventional gasoline must meet the Complex Model II compliance standards which cannot exceed average 1990 levels of toxic and nitrogen oxide emissions.[2]

Oxygenated gasoline is assumed to have specifications identical to conventional gasoline, with the exception of a higher oxygen requirement, specifically 2.7 percent oxygen by weight. Some areas that require oxygenated gasoline will also require reformulated gasoline. For the sake of simplicity, the areas of overlap are assumed to require gasoline meeting the reformulated specifications.

Cellulosic biomass feedstock supplies and costs are taken from the NEMS Renewable Fuels Model. Initial capital costs for biomass cellulosic ethanol were obtained from a research project reviewing cost estimates from multiple sources.[3] Operating costs and credits for excess electricity generated at biomass ethanol plants were obtained from a survey of recent literature[4] and the USDA Agricultural Baseline Projections to 2015.[5]

Table 11.2. Year Round Gasoline Specifications by Petroleum Administration for Defense Districts (PADD)

PADD	Reid Vapor Pressure (Max PSI)	Aromatics Volume Percent (Max)	Benzene Volume Percent (Max)	2007 Sulfur PPM (Max)	Olefin Volume Percent (Max)	Percent Evaporated at 200°	Percent Evaluated at 300°
Conventional							
PADD I	9.6	26.0	1.1	30.0	11.6	47.1	82.0
PADD II	10.2	26.1	1.1	30.0	11.6	47.1	81.9
PADD III	9.9	26.1	1.1	30.0	11.6	47.1	81.9
PADD IV	10.8	26.1	1.1	30.0	11.6	47.1	81.9
PADD V	9.2	26.7	1.1	30.0	11.7	45.7	81.4
Reformulated							
PADD I	8.5	20.7	0.6	30.0	11.9	50.2	84.6
PADD II	9.5	18.5	0.8	30.0	7.1	50.8	85.2
PADD III	8.6	19.8	0.6	30.0	11.2	51.6	83.9
PADD IV	8.6	19.8	0.6	30.0	11.2	51.6	83.9
PADD V							
Nonattainment	7.9	22.0	0.70	20.0	6.0	49.0	90.0
CARB (attainment)	7.9	22.0	0.70	20.0	6.0	49.0	90.0

Max = Maximum.

PADD = Petroleum Administration for Defense District.

PPM = Parts per Million by Weight.

PSI = Pounds per Square Inch.

Volume percent will change to 0.6 in 2011to meet the MSAT2 ruling.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived using U.S. EPA's Complex Model, and updated with U.S. EPA's gasoline projection survey "Fuel Trends Report: Gasoline 1995-2005", January 2008, EPA420-R-08-002 (http://www.epa.gov/otaq/regs/fuels/rfg/properf/rfgperf.htm). (http://www.epa.gov/otaq/regs/fuels/rfg/properf/rfgperf.htm).

Table 11.3. Gasoline Sulfur Content Assumptions, by Region and Gasoline Type, Parts per Million (PPM)

	2004	2005	2006	2007	2008-2030
Conventional					
PADD I	143.4	90.0	43.4	41.7	30
PADD II	111.6	60.0	32.2	32.2	30
PADD III	114.5	60.0	32.4	32.4	30
PADD IV	140.0	90.0	44.2	44.2	30
PADD V	122.8	70.0	33.7	33.7	30
Reformulated					
PADD I-IV	30	30	30	30	30
PADD V	20	20	20	20	20

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived from Form EI-810 "Monthly Refinery Report" and U.S. Environmental Protection Agency, "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control requirements, February 2000, (Washington, DC).

Corn supply prices are estimated from the USDA baseline projections to 2017.[6] The capital cost of a 50-million-gallon-per-year corn ethanol plant was assumed to be $77 million (2007 $). Operating costs of corn ethanol plants are obtained from USDA survey of ethanol plant costs[7]. Energy requirements are obtained from a study of carbon dioxide emissions associated with ethanol production.[8]

Reformulated gasoline has been required in many areas in the United States since January 1995. In 1998, the EPA began certifying reformulated gasoline using the "Complex Model," which allows refiners to specify reformulated gasoline based on emissions reductions from their companies' respective 1990 baselines or the EPA's 1990 baseline. The PMM reflects "Phase 2" reformulated gasoline requirements which began in 2000. The PMM uses a set of specifications that meet the "complex Model" requirements, but it does not attempt to determine the optimal specifications that meet the "Complex Model." (Table 11.4).

Table 11.4. Market Share for Gasoline Types by Census Division

Gasoline Type/Year	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
Conventional Gasoline	19	42	81	64	82	95	74	75	24
Oxygenated Gasoline (2.7% oxygen)	0	0	0	27	0	0	1	12	2
Reformulated Gasoline	81	58	19	9	18	5	25	12	74

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived from EIA-782C, "Monthly Report of Prime Supplier Sales of Petroleum Products Sold for Local Consumption," January-December 2007.

AEO2009 assumes MTBE was phased out by the end of 2007 as a result of decisions made by the petroleum industry to discontinue MTBE blending with gasoline. Ethanol is assumed to be used in areas where reformulated or oxygenated gasoline is required. Federal reformulated gasoline (RFG) is blended with 10% ethanol; oxygenated gasoline is blended with 10% ethanol; and California Air Resources Board (CARB) RFG is blended with up to 10% ethanol. Ethanol is also allowed to blend into conventional gasoline at up to 10 percent by volume, depending on its blending value and relative cost competitiveness with other gasoline blending components. EISA2007 defines a requirements schedule for having renewable fuels blended into transportation fuels by 2022.

Reid Vapor Pressure (RVP) limitations are effective during summer months, which are defined differently by consuming regions. In addition, different RVP specifications apply within each refining region, or PADD. The PMM assumes that these variations in RVP are captured in the annual average specifications, which are based on summertime RVP limits, wintertime estimates, and seasonal weights.

Within the PMM, total gasoline demand is disaggregated into demand for conventional, oxygenated, and reformulated gasoline by applying assumptions about the annual market shares for each type. In *AEO2009* the annual market shares for each region reflect actual 2007 market shares and are held constant throughout the projection. (See Table 11.4 for *AEO2009* market share assumptions.)

Diesel Fuel Specifications and Market Shares

In order to account for diesel desulphurization regulations related to Clean Air Act Amendment of 1990 (CAAA90), low-sulfur diesel is differentiated from other distillates. In NEMS, the Pacific Region (Census Division 9) is required to meet CARB standards. Both Federal and CARB standards currently limit sulfur to 15 ppm.

AEO2009 incorporates the "ultra-low-sulfur diesel" (ULSD) regulation finalized in December 2000. ULSD is highway diesel that contains no more than 15 ppm sulfur at the pump. The ULSD regulation includes a phase-in period under the "80/20" rule, that requires the production of a minimum 80 percent ULSD for highway use between June 2006 and June 2010, and a 100 percent requirement for ULSD thereafter. As NEMS produces annual average results, only a portion of the production of highway diesel in 2006 is subject to the 80/20 rule and the 100 percent requirement does not cover all highway diesel until 2011.

NEMS models ULSD as containing 7.5 ppm sulfur at the refinery gate in 2006, phasing down to 7ppm sulfur by 2011. This lower sulfur limit at the refinery reflects the general consensus that refiners will need to produce diesel with a sulfur content below 10 ppm to allow for contamination during the distribution process.

It is assumed that revamping (retrofitting) existing refinery units to produce ULSD will be undertaken by refineries representing two-thirds of highway diesel production and that the remaining refineries will build new units. The capital cost of revamping is assumed to be 50 percent of the cost of adding a new unit.

The amount of ULSD downgraded to a lower value product because of sulfur contamination in the distribution system is assumed to be 7.8 percent at the start of the program, declining to 2.2 percent at full implementation. The decline reflects the expectation that the distribution system will become more efficient at handling ULSD with experience.

A revenue loss is assumed to occur when a portion of ULSD that is put into the distribution system is contaminated and must be sold as a lower value product. The amount of the revenue loss is estimated offline based on earlier NEMS results and is included in the AEO2009 ULSD price projections as a distribution cost. The revenue loss associated with the 7.8 percent downgrade assumption for 2009 is 0.7 cents per gallon. The revenue loss estimate declines to 0.2 cents per gallon after 2010 to reflect the assumed decline to 2.2 percent.

The capital and operating costs associated with ULSD distribution are based on assumptions used by the EPA in the Regulatory Impact Analysis (RIA) of the rule.[9] Capital costs of 0.7 cents per gallon are assumed for additional storage tanks needed to handle ULSD during the transition period. These capital expenditures are assumed to be fully amortized by 2011. Additional operating costs for distribution of highway diesel of 0.2 cents per gallon are assumed over the entire projection period. Another 0.2 cent cost per gallon is assumed for lubricity additives. Lubricity additives are needed to compensate for the reduction of aromatics and high-molecular-weight hydrocarbons stripped away by the severe hydrotreating used in the desulphurization process.

Demand for highway-grade diesel, both 500 ppm and ULSD combined, is assumed to be equivalent to the total transportation distillate demand. Historically, highway-grade diesel supplies have nearly matched total transportation distillate sales, although some highway-grade diesel has gone to nontransportation uses such as construction and agriculture.

The energy content of ULSD is assumed to decline from that of 500 ppm diesel by 0.5 percent because undercutting and severe desulphurization will result in a lighter stream composition than that for 500 ppm diesel.

AEO2009 incorporates the “nonroad, locomotive, and marine” (NRLM) diesel regulation finalized in May 2004. The PMM model has been revised to reflect the nonroad rule and re-calibrated for market shares of highway, NRLM diesel, and other distillate (mostly heating oil, but excluding jet fuel and kerosene). The NRLM diesel rule follows the highway diesel rule closely and represents an incremental tightening of the entire diesel pool. The demand for high sulfur distillate is expected to diminish over time, while the demand for ULSD (both highway and NRLM) is expected to increase over time.

The final NRLM rule is implemented in multiple steps and requires sulfur content for all NRLM diesel fuel produced by refiners to be reduced to 500 ppm starting mid-2007. It also establishes a new ultra-low-sulfur diesel (ULSD) limit of 15 ppm for nonroad diesel by mid-2010. For locomotive and marine diesel, the rule establishes an ULSD limit of 15 ppm in mid-2012.

End-Use Product Prices

End-use petroleum product prices are based on marginal costs of production plus production-related fixed costs plus distribution costs and taxes. The marginal costs of production are determined within the LP and represent variable costs of production, including additional costs for meeting reformulated fuels provisions of the CAAA90. Environmental costs associated with controlling pollution at refineries are implicitly assumed in the annual update of the refinery investment costs for the processing units.

The costs of distributing and marketing petroleum products are represented by adding product-specific distribution costs to the marginal refinery production costs (product wholesale prices). The distribution costs are derived from a set of base distribution markups (Table 11.5).

Table 11.5. Petroleum Product End-Use Markups by Sector and Census Division

(2007 dollars per gallon)

Sector/Product	Census Division								
	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
Residential Sector									
Distillate Fuel Oil	0.46	0.54	0.27	0.21	0.40	0.27	0.41	0.19	0.33
Kerosene	0.37	0.39	0.35	0.35	0.38	0.42	0.40	0.83	0.04
Liquefied Petroleum Gases	1.13	1.14	0.69	0.48	1.11	0.99	0.97	0.81	1.07
Commercial Sector									
Distillate Fuel Oil	0.22	0.18	0.10	0.06	0.05	0.05	0.06	-0.04	0.08
Gasoline	0.16	0.18	0.14	0.12	0.12	0.14	0.14	0.14	0.17
Kerosene	0.36	0.35	0.35	0.34	0.37	0.40	0.33	0.81	0.40
Liquefied Petroleum Gases	0.52	0.66	0.57	0.57	0.63	0.60	0.63	0.69	0.61
Low-Sulfur Residual Fuel Oil	0.48	0.01	1.10	1.10	-0.03	1.20	0.00	0.75	1.33
Utility Sector									
Distillate Fuel Oil	0.00	0.00	0.00	0.00	0.00	0.0	0.00	0.00	0.00
High-Sulfur Residual Fuel Oil[1]	0.17	-0.13	1.10	0.86	-0.13	-0.29	1.04	0.86	1.35
Low-Sulfur Residual Fuel Oil[1]	-0.11	-0.13	0.81	0.86	-0.13	-0.29	0.80	0.61	0.86
Transportation Sector									
Distillate Fuel Oil	0.32	0.26	0.18	0.14	0.17	0.17	0.18	0.16	0.22
E85[2]	0.12	0.16	0.11	0.09	0.11	0.11	0.11	0.11	0.12
Gasoline	0.15	0.21	0.14	0.12	0.14	0.14	0.14	0.14	0.15
High-Sulfur Residual Fuel Oil[1]	0.11	-0.07	0.22	0.30	0.14	0.22	0.21	0.43	-0.13
Jet Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquefied Petroleum Gases	0.38	0.57	0.78	0.78	0.66	0.77	0.74	0.66	0.55
Industrial Sector									
Asphalt and Road Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distillate Fuel Oil	0.23	0.21	0.18	0.14	0.11	0.13	0.13	0.05	0.09
Gasoline	0.16	0.19	0.14	0.11	0.14	0.14	0.14	0.14	0.15
Kerosene	0.00	0.00	0.00	0.01	0.01	0.04	0.11	0.41	0.00
Liquefied Petroleum Gases	0.55	0.64	0.51	0.50	0.56	0.44	0.51	0.70	0.62
Low-Sulfur Residual Fuel Oil	0.45	-0.15	1.01	0.96	0.44	0.99	0.75	-0.18	0.13

[1]Negative values indicate that average end-use sales prices were less than wholesale prices. This often occurs with residual fuel which is produced as a byproduct when crude oil is refined to make higher value products like gasoline and heating oil.

[2]74 percent ethanol and 26 percent gasoline.

Sources: Markups based on data from Energy Information Administration (EIA), Form EIA-782A, *Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report*; EIA, Form EIA-782B, *Resellers'/Retailers' Monthly Petroleum Report Product Sales Report*; EIA, Form FERC-423, *Monthly Report of Cost and Quality of Fuels for Electric Plants*; EIA, Form EIA-759 *Monthly Power Plant Report; EIA, State Energy Data Report 2006, Consumption (November 2008); EIA, State Energy Data 2006: Prices and Expenditures* (November 2008).

State and Federal taxes are also added to transportation fuels to determine final end-use prices (Tables 11.6 and 11.7). Recent tax trend analysis indicates that State taxes increase at the rate of inflation, therefore, State taxes are held constant in real terms throughout the projection. This assumption is extended to local taxes which are assumed to average 2 cents per gallon.[10] Federal taxes are assumed to remain at current levels in accordance with the overall *AEO2009* assumption of current laws and regulations. Federal taxes are deflated to constant 2007$ as follows:

$$\text{Federal Tax}_{\text{product, year}} = \text{Current Federal Tax}_{\text{product}} / \text{GDP Deflator}_{\text{year}}$$

Table 11.6. State and Local Taxes on Petroleum Transportation Fuels by Census Division, as of July 2008
(2007 dollars per gallon)

	Census Division								
Year/Product	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
Gasoline[1]	0.28	0.24	0.23	0.21	0.18	0.20	0.20	0.21	0.21
Diesel	0.24	0.28	0.22	0.21	0.21	0.18	0.19	0.23	0.21
Liquefied Petroleum Gases	0.13	0.13	0.18	0.20	0.19	0.18	0.14	0.15	0.06
E85[2]	0.25	0.26	0.25	0.22	0.19	0.20	0.22	0.23	0.23
Jet Fuel	0.07	0.05	0.00	0.03	0.05	0.06	0.03	0.04	0.03

[1]Tax also applies to gasoline consumed in the commercial and industrial sectors.

[2] 74 percent ethanol and 26 percent gasoline.

Source: "Compilation of United States Fuel Taxes, Inspection, Fees and Environmental Taxes and Fees," Defense Energy Support Center, Editions 2008-10, July 3, 2008

Table 11.7 Federal Taxes, as of 2008
(Nominal dollars per gallon)

Product	Tax
Gasoline	0.18
Diesel	0.24
Jet Fuel	0.04
Liquefied Petroleum Gases[3]	0.183
M85[1]	0.09
E85[2]	0.20

[1]85 percent methanol and 15 percent gasoline.

[2]74 percent ethanol and 26 percent gasoline.

[3]2010 data-based on EPACT05: excise tax is 4.3 cents/gal after 9-30-2011 and 18.3 cents/gal prior to that. A credit of 50 cents/gal is also applied between 10-1-06 and 9-30-09.

Sources: Omnibus Budget Reconciliation Act of 1993 (H.R. 2264); Tax Payer Relief Act of 1997 (PL 105-34), Clean Fuels Report (Washington, DC, April 1998) and Energy Policy Act of 2005 (PL 109-58). IRS Internal Revenue Bulletin 2006-43 available on the web at http://www.irs.gov/pub/irs-irbs/irb06-43.pdf

Crude Oil Quality

In the PMM, the quality of crude oil is characterized by average gravity and sulfur levels. Both domestic and imported crude oil are divided into five categories as defined by the ranges of gravity and sulfur shown in Table 11.8.

Table 11.8. Crude Oil Specifications

Crude Oil Categories	Sulfur (percent)	Gravity (degrees API)
Low Sulfur Light	0 - 0.5	25 - 60
Medium Sulfur Heavy	0.35 - 1.1	26 - 40
High Sulfur Light	> 1.1	>32
High Sulfur Heavy	> 1.1	24 - 33
High Sulfur Very Heavy	> 0.9	< 23

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived from EI-810, "Monthly Refinery Report" data.

A "composite" crude oil with the appropriate yields and qualities is developed for each category by averaging the characteristics of specific crude oil streams in the category. While the domestic and foreign categories are the same, the composite crudes for each category may differ because different crude streams make up the composites. For domestic crude oil, estimates of total regional production are made first, then shared out to each of the five categories based on historical data. For imported crude oil, a separate supply curve is provided for each of the five categories. Each import supply curve is linked to a world oil supply market balance for that crude type, such that the quantity of crude oil imported depends on the economic competition with use by the rest of the world.

Capacity Expansion

PMM allows for capacity expansion of all processing unit types including distillation, vacuum distillation, hydrotreating, coking, fluid catalytic cracking, hydrocracking, and alkylation manufacturing. Capacity expansion occurs by processing unit, starting from base year capacities established by PADD using historical data.

Expansion occurs in NEMS when the value received from the additional product sales exceeds the investment and operating costs of the new unit. The investment costs assume a financing ratio of 60 percent equity and 40 percent debt, with a hurdle rate and an after-tax return on investment of about 9 percent. Capacity expansion plans are determined every 3 years. For example, the PMM looks ahead in 2008 and determines the optimal capacities given the estimated demands and prices expected in the 2011 projection year. The PMM then allows any of that capacity to be built in each of the projection years 2009, 2010, and 2011. At the end of 2011 the cycle begins anew, looking ahead to 2014. ACU capacity under construction that is expected to begin operating during by 2010 is added to existing capacities in their respective start year. Capacity expansion is also modeled for corn and cellulosic ethanol, coal-to-liquids, gas-to-liquids, and biomass-to-liquids production.

Biofuels Supply

The PMM provides supply functions on an annual basis through 2030 for ethanol produced from both corn and cellulosic biomass to produce transportation fuel. It also assumes that small amounts of vegetable oil and animal fats are processed into biodiesel, a blend of methyl esters suitable for fueling diesel engines.

- Corn feedstock supplies and costs are provided exogenously to NEMS. Feedstock costs reflect credits for co-products (livestock feed, corn oil, etc.). Feedstock supplies and costs reflect the competition between corn and its co-products and alternative crops, such as soybeans and their co-products.

- Cellulosic (biomass) feedstock supply and costs are provided by the Renewable Fuels Module in NEMS. Cellulosic ethanol production and biomass-to-liquids (BTL) production compete for this feedstock.

- The Federal motor fuels excise tax credit for ethanol is 51 cents per gallon of ethanol (5.1 cents per gallon credit to gasohol at a 10-percent volumetric blending portion) is applied within the model. The tax credit is held constant in nominal terms, decreasing with inflation throughout the projection in constant dollar terms. It is assumed that the credit expires after 2010.

To model the new Renewable Fuels Standard in EISA2007, several assumptions were required. In addition to using the text of the legislation it was also assumed that rules promulgated under the RFS in EPACT05 would govern the administration of the EISA2007 RFS

- The penetration of cellulosic ethanol into the market is limited before 2012 to the projects (co-sponsored by DOE grants) currently scheduled to produce approximately 150 million gallons per year.

- Biomass-to-Liquid (Fischer-Tropsch) diesel fuel production contributes 1.5 credits towards the cellulosic mandate.

- Imported cane ethanol counts toward the advanced renewables mandate. In addition, a limited supply of cellulosic ethanol would be available for import and would count toward the cellulosic mandate.

- The cellulosic biofuel waiver, when activated, reduces the cellulosic, advanced, and total requirement by that amount in all future years. In years beyond 2022, the last year specified in the EISA, the RFS mandate levels are held constant.

- It is assumed that biodiesel and BTL diesel may be consumed in diesel engines without significant infrastructure modification (either vehicles or delivery infrastructure).

- Ethanol is assumed to be consumed as either E10 or E85, with no intermediate blends. The cost of placing E85 pumps at the most economic stations is spread over all transportation fuels. Using this assumption, the E10 blending market is assumed to be saturated and the E85 market consumes additional ethanol after 2014.

- To accommodate the ethanol requirements in particular, transportation modes are expanded or upgraded for both E10 and E85, and it is assumed that most ethanol originates from the Midwest, with transportation costs ranging from a low of 1.7 cents per gallon for expanded distribution in the Midwest, to as high as 2.6 cents per gallon for the Southeast and West Coast.

- For E85 dispensing stations, it is assumed the average cost of a retrofit and new station is about $45,000 per station, which translates into an incremental cost per gallon ranging from 26 cents in 2013 to 4.4 cents by 2020, depending on the average sales per dispenser.

- The total projected incremental infrastructure cost (transportation, distribution, dispensing) for E85 varies from 27 cents per gallon in 2013 to 6 cents per gallon in 2020

Interregional transportation is assumed to be by rail, ship, barge, and truck, and the associated costs are included in PMM. A subsidy is offered by the Department of Agriculture's Commodity Credit Corporation for the production of biodiesel. In addition, the American Jobs Creation Act of 2004 provides an additional tax credit of $1 per gallon of soybean oil for biodiesel and 50 cents per gallon for yellow grease biodiesel until 2006, and EPACT05 extended the credit again to 2008. The Emergency Stabilization Act of 2008 extended it again to 2009 and increased the yellow grease credit to $1 per gallon.

Gas-To-Liquids, Coal-To-Liquids, and Gasification Technologies

Gas-to-liquids (GTL) facilities convert natural gas into distillates, and are assumed to be built if the prices for lower sulfur distillates reach a high enough level to make it economic. In the PMM, gas-to-liquids facilities are assumed to be built only on the North Slope of Alaska, where the distillate product is transported on the Trans-Alaskan Pipeline System (TAPS) to Valdez and shipped to markets in the lower 48 States. The earliest start date for a GTL facility is set at 2017. Also, the source of feedstock gas to any GTL facility in Alaska is assumed to be from undiscovered, non-associated resources which will be more costly than the current, largely associated proved reserves on the North Slope, which are assumed to be dedicated to the pipeline. The GTL facilities are built incrementally, with output volumes of 34,000 barrels per day, at an capital cost of $52,023 per barrel of daily capacity (2007 dollars). Variable operating costs are assumed to be $4.67 per barrel (2007 dollars). The transportation cost to ship the GTL product from the North Slope to Valdez along the TAPS is assumed to be

the price set to move oil (i.e. the TAPS revenue recovery rate). This rate is a function of allowable costs, profit, and flow, and can change over the projection.

It is also assumed that coal-to-liquids (CTL) facilities will be built when low-sulfur distillate prices are high enough to make them economic. One CTL facility is capable of processing 21,800 tons of coal per day, with a production capacity of 50,000 barrels of synthetic fuels per day and 200 megawatts of capacity for electricity cogeneration sold to the grid.[11] A CTL facility of this size is assumed to cost about $3.97 billion in initial capital investment (2007 dollars). CTL facilities could be built near existing refineries. For the East Coast, potential CTL facilities could be built near the Delaware River basin; for the Central region, near the Illinois River basin or near Billings, Montana; and for the West Coast, in the vicinity of Puget Sound in Washington State. The CTL yields are assumed to be similar to those from a GTL facility, because both involve the Fischer-Tropsch process to convert syngas ($CO + H_2$) to liquid hydrocarbons. The primary yields would be distillate and kerosene, with additional yields of naphthas and liquefied petroleum gases. Petroleum products from CTL facilities are assumed to be competitive when distillate prices rise above the cost of CTL production (adjusted for credits from the sale of cogenerated electricity). It is assumed that CTL facilities can only be built after 2010.

Gasification of petroleum coke (petcoke) and heavy oil (asphalt, vacuum resid, etc.) is represented in AEO2009. The PMM assumes petcoke to be the primary feedstock for gasification, which in turn could be converted to either combined heat and power (CHP) or hydrogen production based on refinery economics. A typical gasification facility is assumed to have a capacity of 2,000 ton-per-day (TPD) which includes the main gasifier and other integrated units in the refinery such as air separation unit (ASU), syngas clean-up, sulfur recovery unit (SRU), and two downstream process options - CHP or hydrogen production. Currently, there is more than 5,000 TPD gasification capacity in the U.S. that produces CHP and hydrogen. Additional gasification capacity is projected to be built in the AEO2009 projection, primarily for CHP production.

Combined Heat and Power (CHP)

Electricity consumption in the refinery is a function of the throughput of each unit. Sources of electricity consist of refinery power generation, utility purchases, refinery CHP, and merchant CHP. Power generators and CHP plants are modeled in the PMM linear program as separate units which are allowed to compete along with purchased electricity. Both the refinery and merchant CHP units provide estimates of capacity, fuel consumption, and electricity sales to the grid based on historical parameters.

Refinery sales to the grid are estimated using the following percentages which are based on 2005 data:

Region	Percent Sold To Grid
PADD I	67.0
PADD II	0.9
PADD III	2.2
PADD IV	0.9
PADD V	45.4

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived using EIA-860B, "Annual Electric Generators Report-Nonutility"

Merchant CHP plants are defined as non-refiner owned facilities located near refineries to provide energy to the open market and to the neighboring refinery. These sales occur at a price equal to the average wholesale price of electricity in each PMM region, which are obtained from the Electricity Market Model.

Short-term Methodology

Petroleum balance and price information for 2008 and 2009 are projected at the U.S. level in the *Short-term Energy Outlook*, (*STEO*). The PMM adopts the *STEO* results for 2008 and 2009, using regional estimates derived from the national *STEO* projections.

Legislation and Regulations

The Tax Payer Relief Act of 1997 reduced excise taxes on liquefied petroleum gases and methanol produced from natural gas. The reductions set taxes on these products equal to the Federal gasoline tax on a Btu basis.

Title II of CAAA90 established regulations for oxygenated and reformulated gasoline and reduced-sulfur (500 ppm) on-highway diesel fuel. These are explicitly modeled in the PMM. Reformulated gasoline represented in the PMM meets the requirements of phase 2 of the Complex Model, except in the Pacific region where it meets CARB 3 specifications.

AEO2009 reflects "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements finalized by EPA in February 2000. This regulation requires that the average annual sulfur content of all gasoline used in the United States be phased-down to 30 ppm between the years 2004 and 2007. The 30 ppm annual average standard is not fully realized in conventional gasoline until 2008 due to allowances for small refineries.

AEO2009 reflects Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements finalized by the EPA in December 2000. Between June 2006 and June 2010, this regulation requires that 80 percent of highway diesel supplies contain no more than 15 ppm sulfur while the remaining 20 percent of highway diesel supplies contain no more than 500 ppm sulfur. After June 2010, all highway diesel is required to contain no more than 15 ppm sulfur at the pump.

AEO2009 reflects nonroad locomotive and marine (NRLM) diesel requirements finalized by the EPA in May 2004. Between June 2007 and June 2010, this regulation requires that nonroad diesel supplies contain no more than 15 ppm sulfur. For locomotive and marine diesel, the action establishes a NRLM limit of 15 ppm in mid-2012.

AEO2009 incorporates the American Jobs Creation Act of 2004 to extend the Federal tax credit of 51 cents per gallon of ethanol blended into gasoline through 2010.

AEO2009 represents major provisions in the Energy Policy Act of 2005 (EPACT05) concerning the petroleum industry, including: 1) removal of oxygenate requirement in RFG; and 2) extension of tax credit of $1 per gallon for soybean oil biodiesel and $0.50 per gallon for yellow grease biodiesel through 2008.

AEO2009 includes provisions outlined in the Energy Independence and Security Act of 2007 (EISA2007) concerning the petroleum industry, including a renewable Fuels Standard increasing total U.S. consumption of renewable fuels. Although the statute calls for higher levels, due to uncertainty about whether the new RFS schedule can be achieved and the stated mechanisms for reducing the cellulosic biofuel schedule, the final schedules in PMM were assumed to be: 1) 30.9 billion gallons in 2023 for all fuels; 2) 15.9 billion gallons in 2023 for advanced biofuels; 3) 10.9 billion gallons in 2023 for cellulosic biofuel; 4) 1 billion gallons of biodiesel by 2023.[12]

AEO2009 includes the EPA Mobil Source Air Toxics (MSAT 2) rule which includes the requirement that all gasoline products (including reformulated and conventional gasoline) produced at a refinery during a calendar year will need to contain no more than 0.61 percent benzene by volume. This does not include gasoline produced or sold in California which is already covered by the current California Phase 3 Reformulated Gasoline Program.

Due to the uncertainty surrounding compliance options, *AEO2009* did not include any explicit modeling treatment of the International Maritime Organization's "MARPOL Annex 6" rule covering cleaner marine fuels and ocean ship engine emissions.

Notes and Sources

[1] U.S. Environmental Protection Agency, “Tier 2” Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements, February 2000, (Washington, DC).

[2] Federal Register, Environmental Protection Agency, 40 CFR Part 80, Regulation of Fuels and Fuel Additives: Standards for Reformulated and Conventional Gasoline, Rules and Regulations, p. 7800, (Washington, DC, February 1994).

[3] Marano, John, "Alternative Fuels Technology Profile: Cellulosic Ethanol", March 2008.

[4] Ibid.

[5] U.S. Department of Agriculture, "USDA Agricultural Baseline Projections to 2017," February 2008, http://www.ers.usda.gov/publications/oce081.

[6] Ibid

[7] Shapouri Hosein; Gallagher, Paul; and Graboski, Mike. USDA’s 1998 Ethanol Cost-of-Production Survey. January 2002.

[8] Marland, G. and A.F. Turhollow. 1991. "CO2 Emissions from the Production and Combusion of Fuel Ethanol from Corn." Energy, 16(11/12):1307-1316.

[9] U.S. Environmental Protection Agency, Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements, EPA420-R-00-026 (Washington, DC, December 2000).

[10] American Petroleum Institute, *How Much We Pay for Gasoline*: 1996 Annual Review, May 1997.

[11] Marano, John, "Alternative Fuels Technology Profile: Coal to Liquids", March 2008.

[12] The 2023 RFS levels used in the PMM reinstates the temporary reductions (1.1 billion gallons) that were needed in 2022 for the *all fuels*, *advanced biofuels*, and *cellulosic biofuel* categories